Chapter Twenty-Five – Transmission System Operations - Control and Dispatch

I. Introduction

Transmission systems carry electricity from several different generation plants, via multiple alternative paths, over several miles, to substations that deliver electricity to a distribution system and to end-use customers. Transmission system control includes the selection of which alternative paths are to be used. Transmission system dispatch includes the selection of how much electricity to carry on each particular line. This chapter presents the results of Liberty's investigation of the control and dispatch portions of ComEd's transmission system operations. Chapter Twenty-Three presented the results of Liberty's review of the maintenance and inspection portions of ComEd's transmission system operations.

The objectives of Liberty's investigation were to evaluate ComEd's: (a) "real-time" operational control of its transmission system, (b) transmission system Supervisory Control and Data Acquisition *(SCADA)* hardware and software capabilities, and (c) pre-planned transmission system operational procedures, such as emergency load shedding and system restoration. In addition, Liberty's investigation provided the answers to several specific questions that were posed by the ICC Staff.

The evaluation criteria that Liberty established for its investigation of ComEd's transmission system control and dispatch operations were:

(1) ComEd should have had a state-of-the-art SCADA system.

(2) ComEd's operators should have been provided with adequate training.

(3) ComEd's operators should have been provided with appropriate pre-planned operational procedures.

(4) ComEd should have had effective management oversight of its transmission system operators.

Liberty found that ComEd had a state-of-the-art SCADA system for its transmission system, but that its transmission system operators were not provided with state-of-the-art simulator training. ComEd's system operators had been provided with appropriate pre-planned operational procedures. ComEd had effective management oversight, system operators conducted economic dispatch effectively, and ComEd had unusual success in selling off its low-load excess nuclear generation.

II. Background and Analysis

A. System Surveillance

ComEd maintained a constant, twenty-four hours-a-day, seven days-a-week, real-time surveillance of its transmission system. ComEd's two key surveillance sites were the Bulk Power Operations Transmission Dispatch Center and the Distribution Dispatch and Control Center. The Bulk Power Operations Dispatch Center is commonly referred to as the "Block House" because of its window-less monolithic concrete construction that is designed to withstand the effects of tornadoes.

The Distribution Dispatch and Control Center is equipped with stand-by facilities so that it can substitute for the Block House in the event of a loss-of-site catastrophe. The ComEd regional offices are equipped with stand-by facilities so that they can each substitute for the Distribution Dispatch and Control Center, in their region, in the event of a loss-of-site catastrophe.

System operators, in the Block House, use ComEd's Energy Management System *(EMS)* and Supervisory Control and Data Acquisition *(SCADA)* system to monitor every generation plant feeding into ComEd's system, every transmission tie-line that connects ComEd's system with a neighboring utility's transmission system, every ComEd transmission line, and every ComEd transmission substation. Similarly, Dispatchers in ComEd's Distribution Dispatch Centers use ComEd's SCADA system to monitor most of ComEd's distribution substations and many of the individual feeders in ComEd's distribution system.

The input end of ComEd's SCADA system begins with a RTU, a real-time processor with an interface that collects data in a substation. Data collected may include voltage levels on each of the substation's buses, current flows in all of the circuits, each circuit breaker's status (open or closed), switch positions (open or closed), transformer adjustable output voltage tap positions, dc-power supply status (for the SCADA system and many of the relays, circuit breakers, and motor operated switches), station battery status, and substation alarms for fire, burglary, entry, transformer temperatures, and other conditions. Remote control from one of the dispatch centers is also performed through the substation RTU.

The RTU encodes the substation's input data and uses a modem to transmit data over a dedicated SCADA communications system: microwave links, telephone lines, power line carrier, and radio. The SCADA's communication system has redundancy for critical data, that is, it has alternative paths so that the data can get through even if one path fails.

Modems in the Block House or regional headquarters buildings receive the data. Computers decode the data, interpret it, and make calculations based upon it. For example, the computers calculate whether the data coming in from the two ends of each transmission line are compatible. If not, then using additional data from the neighborhood of the two line ends, the computers calculate which end's data is most likely to be false. Then they substitute the data that they calculate as being most likely correct ("State Estimation") to replace the likely-false data.

Finally, they issue a "trouble report" about the instruments that gave the likely-false data so that they will be tested and, if necessary, repaired.

After the SCADA data has been cleansed of likely-false data, the Block House's computers use the clean data, and the calculations that they derived from it, to display ComEd's bulk power system on video terminals for the system operators. Typical displays are schematic maps of ComEd's transmission lines and substations, showing the present status of circuit breakers and switches, and annotated with real-time numerical data showing voltages, power flows and reactive power flows. (Reactive power flows are those where the wave forms for the transmission system's voltage and the current are one-quarter of a cycle out of phase with each other. Reactive power flows represent energy that is bouncing back and forth between generation and load, rather than simply being consumed by the load. Reactive power flows are necessary in order to maintain the transmission system's voltage.)

B. System Alarms

Every time that the computers detect a problem on the power system – for example, a line or a transformer being overloaded, a voltage moving out of its correct range, a circuit breaker opening itself, – the computers sound an alarm, log the event on a printed report, and show the problem to the system operators on their displays.

The system operator examines the display and decides how to react to the problem. The operator's decision might be to continue to monitor the situation, or to send an operator out to the field site and investigate, or to make a corrective action on the system. Typical corrective actions are to reroute a power flow, or to switch a circuit, or to increase or decrease generation levels at one or more plants.

To change generation levels, the system operator issues a dispatch order to a power plant's operator. To shed load, the system operator issues an order to the distribution dispatch operator to drop customers. To reroute bulk power or switch a transmission circuit, the system operator initiates action on his computer display terminal. The computer verifies the operator's authority level. If it is high enough, then, after a confirmation, the computer encodes a command to the device that the operator has selected, and sends that command over the SCADA communication system. The substation RTU receives the message, executes the command (operates the device), and sends a confirmation message back to the operator. The operator sees the device's operation on his display. To switch a distribution circuit, the distribution operator uses the distribution dispatch center's computer system similar to the way that system operator uses the system dispatch computer.

C. System Problems

The system operator knows that there is a problem as soon as a transmission circuit breaker opens, a transmission line goes into overload, a line goes to zero flow, a voltage goes out of limit, there is a sudden change in flow on a tie-line to a neighboring utility, a generation unit trips off, there is a substation alarm, or the State Estimation Program detects likely-false data coming from some RTU. Similarly, the distribution operator knows that there is a problem as soon as a SCADA monitored distribution circuit breaker opens, a distribution feeder line goes into overload or goes to zero flow, a voltage goes out of limit, or there is a distribution substation alarm.

Either operator knows the general location of the problem but neither operator knows what caused the problem. Diagnosis of cause, and an estimate of the time necessary to fix the problem, must await field personnel to arrive at the site and identify the exact cause of the problem. Nonetheless, either operator, and particularly the system operator, has the means to switch the system and either bypass the problem or to reduce the effect of the problem.

D. System Contingencies

The system operator is not limited to a reactive response to system problems. The operator is provided with the means to anticipate potential problems and advice on how to safeguard the system against potential problems before they occur (if indeed they occur at all).

ComEd's Security Analysis Program is a computer software program with a pre-filed list of over 450 potential system contingencies, such as the sudden loss of a transmission line.[1] Constantly, the Block House computers take a "snapshot" of the system's status. Next, the computers run through a "what-if" analysis of how the system would respond to each one of the contingencies. For example, what would the transmission system's power flows become if the transmission system were to suddenly lose transmission line number L1234?

If the answer to that question is that the system would become stressed, that is, some transmission line's flow would increase to beyond its capacity, the Security Analysis Program sends a warning to the system operator and to "off-line" transmission operations planning engineers (personnel not in the same room as the on-line system operator). The off-line engineers evaluate the potential problem that the Security Analysis Program has found and, if they deem it to be serious, they devise a correction to avoid the problem, for example by switching flow away from the sensitive transmission lines. After they have devised a correction, the engineers communicate their recommendation to the system operator. The system operator decides what he wants to do (usually following the engineers' recommendation) and then operates the system to do it.

The off-line transmission operations planning engineers' role is not limited to responding to the warnings that the computer sends to them. Each morning, they review the day's and the week's load forecast, the system's resources (power supply), and the transmission system's status (lines in service). Then they simulate the system and identify conditions that might become problematic. After their analysis of the potential problems, they hold discussions with the system operators and reach a consensus on what corrections would be best if the conditions arise.

E. Control Area Regulation

In addition to maintaining a surveillance of ComEd's transmission system, another one of ComEd's system operators' real-time duty is to regulate ComEd's control area. That is, ComEd is responsible for matching generation and load (regulation) within the closed boundaries of ComEd's assigned portion of the North American Eastern Grid (ComEd's control area).

The North American Eastern Grid consists of free-flowing interconnected transmission lines from Southeastern Canada (Ontario, Quebec, New Brunswick) to Florida, and East of Texas, Colorado, Wyoming, and the Dakotas. Free-flowing means that the power flows on the transmission lines follow the laws of physics, not the dictates of any overseer or the control of phase shifting transformers.

The Eastern Grid is divided into regions. Utilities in each region are organized into Regional Reliability Councils. The Eastern Grid includes bounded geographic districts that are called control areas. Where control areas include multiple utilities, one utility is recognized to be in charge of regulating that particular area. Regulation means to attempt to create an exact match between power supply and consumption in that control area.

ComEd is a member of the Mid-America Interconnected Network (MAIN) Regional Reliability Council. MAIN has recognized ComEd to be in-charge of its control area. The other utilities in ComEd's control area are various municipal utilities.[2] ComEd charges these municipal utilities for its control area services.

The computers in the Block House constantly monitor the power flows on each of the transmission lines that cross the boundaries of ComEd's control area. The net power flow out of ComEd's control area is continuously calculated by adding together all of the outbound tie-line flows and subtracting out all of the inbound tie-line flows. If the computers find that the net outflow is positive, say 100 MW, it means that power supply in ComEd's control area is 100 MW more than the load. Unless ComEd (or some other utility in ComEd's control area) is exporting 100 MW of power to another utility outside of the control area at that time, ComEd's system operator must decrease control area generation by 100 MW, plus or minus the control area requirement to maintain frequency at 60 hertz, to stop the out-flow and restore the match between the control area's generation and load.

If the computers find that the net out-flow is negative by say 50 MW, it means that consumption in ComEd's control area is 50 MW more than the power supply. Unless, at this moment, ComEd (or some other utility in ComEd's control area) happens to be buying an import of 50 MW of power from another utility outside of the control area, that means that ComEd's system operator must increase generation by 50 MW in order to push back the in-flow and restore the match between the control area's generation and load.

Note that a control area can have a match between its own generation and load, and have a large in-flow of power into one side of its control area while simultaneously having an equally large out-flow out of the other side. (The out-flow, less the in-flow, net to zero.) If this "through-flow" (in-out) is due to a power purchase and sale between two other utilities, neither of which is inside of the control area, then the control area is providing "wheeling" for that power purchase/sale transaction.

If the through-flow is due to the electrical parameters of the transmission system in the region, the through-flow is called circulation. Circulation is a whirlpool in the grid that usually involves many control areas flowing East-to-West through some while simultaneously flowing West-to-East through others. ComEd has surrounded the City of Chicago with nine phase shifting transformers in order to reduce the circulating flow through Chicago's transmission grid that would otherwise be caused by Wisconsin's power purchases. (Circulation may indicate the need for transmission system re-design, coordinated on a regional basis, to stop the waste of the transmission system's flow capacity.) If the through-flow is due to some other control area performing its regulation poorly, then it is called "inadvertent flow" and it indicates that MAIN needs to take action against the offending control area's in-charge utility.

F. Economic Dispatch

Economic Dispatch is the process by which the system operator balances power supply and consumption at the least cost.

ComEd has many alternative choices for its power supply, including dozens of individual generation units, hundreds of opportunities to purchase electric power from other utilities, non-utility generators, and power brokers. Each power supply alternative has its own unique cost.

The table below summarizes ComEd's 1999 power supply by plant, and each plant's fuel cost rate,[3] the fuel cost divided by energy output. Economic dispatch decisions depend upon variable costs only. Fixed costs are irrelevant. Fuel is by far the predominant variable cost component in any economic dispatch decision. Also listed is ComEd's average purchased power cost rate.[4]

The table is sorted into "merit order" – from ComEd's lowest fuel cost rate source to its most expensive – in dollars per MegaWatt-hour ($/MWh). Also shown is each source's percentage contribution to ComEd's total power supply.

Power Supply Cost Rates, 1999

Plant	Fuel	Fuel Cost	MWh	Rate	% of Total
Braidwood	Nuclear	$88,505	18,935,719	$4.67	17.09
Byron	Nuclear	88,441	18,082,590	4.89	16.32
Dresden	Nuclear	65,534	12,359,478	5.30	11.16
Quad Cities	Nuclear	53,916	9,686,144	5.57	8.74
LaSalle County	Nuclear	84,092	14,620,354	5.75	13.20
Powerton	Coal	119,613	6,821,506	17.53	6.16
Fisk	Coal/Gas	23,614	1,125,765	20.98	1.02
Will County	Coal	71,575	3,369,300	21.24	3.04
Waukegan	Coal/Gas	73,821	3,468,706	21.28	3.13
Crawford	Coal/Gas	32,897	1,396,638	23.55	1.26
Joliet	Coal/Gas	214,367	7,454,597	28.76	6.73
Crawford GT	Oil/Gas	433	14,868	29.13	0.01
Collins	Oil/Gas	71,938	2,235,890	32.17	2.02
Joliet IC	Oil	30	848	35.80	0.00
Lombard Jet	Gas	552	11,570	47.70	0.01
Purchased Pwr	N/A	551,575	11,077,588	49.79	10.00
Electric Junction GT	Gas	1,412	24,818	56.91	0.02
Joliet GT	Gas	1,020	16,732	60.98	0.01
Sabrooke GT	Oil	555	8,975	61.86	0.01
Bloom GT	Oil	236	3,243	72.73	0.00
Calumet GT	Gas	1,100	14,814	74.24	0.01
Fisk Jet	Oil	374	4,785	78.07	0.00
Waukegan Jet	Oil	639	4,903	130.33	0.00
Common costs	N/A	2,596	0	N/A	0.00
Miscellaneous	N/A	0	33,760	N/A	0.03
TOTAL:		1,548,837	110,773,591	13.98	100.00

Note: GT = Gas Turbine, IC = Internal Combustion engine (diesel), Jet = commercial aircraft Jet engine, N/A = Not Applicable.

Nuclear power plants were the ComEd's least expensive power sources. Those power supply cost rates ranged from Braidwood, at $4.67 in fuel costs per MWh of energy output to LaSalle County, at $5.75 per MWh. Since these nuclear plants were ComEd's least cost power sources, these were the sources that ComEd's system operator dispatched first. ComEd's nuclear plants provided 66.51 percent of ComEd's 1999 power supply – about two-thirds of the total.

ComEd's second least costly power supply was from its conventional steam fossil-fuel burning plants: from Powerton at $17.53 per MWh to Collins at $32.17 per MWh. All together, ComEd's fossil-fueled steam plants provided 23.36 percent of ComEd's 1999 power supply – less than one-quarter.

ComEd's third least power supply was what it purchased from other utilities at an average cost of $49.79 per MWh for 10.00 percent of ComEd's 1999 power supply – one-tenth.

ComEd's most costly power supply source was from its own peaking units: gas turbines, diesels, and jet engines. These cost from $29.13 to $130.33 per MWh for 0.13 percent of ComEd's 1999 power supply.

Despite being more than twenty times as expensive as nuclear units, peaking units are nonetheless essential to the reliability of the system. Peaking units can come on-line and serve load within ten minutes. Nuclear units and conventional units may take days to get on-line. Thus peaking units provide an invaluable resource during emergencies – but at a high cost.

G. System Dispatch

ComEd's power supply fuel cost rates provide a valuable snapshot of ComEd's merit order – from Braidwood to Waukegan. However, there are additional factors involved in the system operators dispatch selections.

1. Incremental Costs

A generation unit's power production cost rate varies with its output level. For example, a fossil-fuel burning unit, with a capacity of 600 MW and a minimum of 400 MW, will consume far more fuel to increase its output by an increment of one MW, going from 599 MW to 600 MW, than it will going the same increment from 400 MW to 401 MW. Thus, the computer that assists the system operator with economic dispatch selections, must take into account the exact real-time generation level of each power source, and detailed costs models of the unit's incremental cost to go from one generation level to the next. At a given output level, the unit's incremental cost, divided by its increment of generation, is called the unit's incremental cost rate at that output level.

2. Time Lags

A nuclear generation unit experiences time-delayed effects from reducing its generation level. A decision to cut-back a nuclear unit now will influence how it can be dispatched days and weeks from now. Thus, the computer that assists the system operator with economic dispatch selections must take into account the time lag effects of changing the dispatch of a nuclear generation unit now and the effects on economic dispatch that will come into effect hours from now.

3. EGC

Economic Generation Control *(EGC)* is ComEd's economic dispatch software.[5] It has detailed data on ComEd's units' production costs. It also has detailed data on the ramp rates (increase or decrease of MW generation, per minute), and the time lag effects of changing the dispatch levels of ComEd's nuclear and coal units.

4. Congestion

The transmission lines carrying power away from an inexpensive generation unit might be actually or potentially overloaded. Consequently, the system operator may need to cut back the output of an inexpensive generation unit, and increase the output of a more expensive generation unit to replace the shortage, despite the increase in power supply costs to the system. This accommodation of the transmission grid's congestion by shifting generation is called "out-of-merit-order dispatch."

H. Unit Commitment

Economic dispatch attempts to minimize power supply costs in real-time. Unit commitment attempts to minimize power supply costs over the whole of ComEd's daily load cycle. For example, at 4 am ComEd's load may be very light. Very few generation sources are needed. That hour's fuel costs could be cut even more if the more expensive units, the ones that are now being dispatched to their minimum operational levels, were shut down completely so that they stopped burning fuel all together.

However, a few hours later, say at 3 pm, the load likely will have become much larger. If ComEd's fuel burning conventional steam units had been shut down at 4 am to save fuel costs, those units would not be able to come back on-line eleven hours later to serve the 3 pm load. Far more expensive units, sometimes called peakers, would then have to be used at 3 pm. Thus, a short-sighted cost savings one hour can have significant cost impact another hour.

In 1999, ComEd's peak load was 21,243 MW, between 2 pm and 3 pm, on July 30, 1999.[6] ComEd's (early morning) low-load is about 8,000 MW.[7] But ComEd's nuclear plant output is about 12,000 MW, creating a "low-load problem" where ComEd must either dispose of as much as 4,000 MW of excess nuclear output or dispatch its nuclear plants to reduced output, with consequential time lag problems.

ComEd states that it has been able to deal with its low-load problem by selling its excess nuclear output in off-system sales.[8] In several other parts of the United States, utilities with similar low-load problems have had to pay other utilities to take their early morning excess nuclear generation. (These have been called "negative price sales.")

ComEd's software, "Automated Dispatch Advisory System" *(ADAS)* assists the system operator with unit commitment.[9] It accepts a ten-day load forecast and production schedules proposed by the operator. ADAS calculates the expected costs for each of the operator's various proposals and identifies the least-cost one. It then goes on to evaluate variations of that proposal to see if it can discover an improvement.

I. Load Forecast

ComEd's ADAS unit commitment requires a ten-day load forecast. ComEd's system operator is assisted by several software packages to help make this short-term load forecast. ComEd's Wholesale Energy Trading Office *(WETO)* also provides the system operator with the load forecast.

ComEd subscribes to weather forecasting services. ComEd has several software packages that search for like-day conditions.[10] Like-days are similar calendar days (weekday versus weekend/holiday), with similar weather (temperature, humidity), and similar futures (the historic day's actual succeeding weather is similar to the current day's weather forecast). Like-day historic hour-by-hour loads are then scaled to produce the current hour-by-hour load forecast.

One of ComEd's load forecasters is an Electric Power Research Institute *(EPRI)* neural-net software package. A neural-net is a particular style of software that is intended to imitate one theory of how the human brain operates. Its principle feature is that it learns, that is, it re-programs itself on the basis of its past successes and failures. Another load forecaster is an Energy Management Systems *(EMS)* package that uses the system operator's manual input. WETO has purchased other software packages for its own use and then provide the system operator with their load forecast.

All of the forecasts are monitored after-the-fact for their accuracy.[11] In the samples reviewed by Liberty, EPRI's neural-net software appeared to be the most accurate, with the system operator close behind. WETO's forecasts were also quite good.

J. Reserves

When the system operator makes ComEd's unit commitment decision, there must be more generation capacity than the anticipated load. In other words there must be a reserve margin. The reserve margin is extra generation capacity to meet contingencies, such as the unscheduled forced outage of some generation unit.

MAIN requires ComEd to maintain an operating reserve capacity. MAIN's definition of operating reserve capacity is set on the basis of an allocation of the largest unit in MAIN plus regulating margin. At time of peak load, ComEd's operating reserve requirement is somewhat above 3 percent. On a Spring or Fall day, it might be twice that. At least one-half of ComEd's operating reserve (which includes regulating margin) must be in on-line spare generation units. No more than one-half of the remaining operating reserve can be in quick start peakers.[12]

If ComEd suffered a sudden capacity shortage system problem – for example, one or more generation units suddenly being forced off-line by a breakdown, or the loss of transmission lines carrying power into ComEd's system – ComEd's first resort is to its own operating reserve by calling upon its spare on-line units or its quick start units to fill the gap. If ComEd's reserves are insufficient, then ComEd has the right to call upon its fellow MAIN members to share their operating reserves. MAIN's rules (MAIN Operating Guide 5B)[13] say that ComEd can call for reserve sharing for no more than 59 minutes after the start of its emergency. MAIN reserve sharing energy is priced at either $100 per MWh or the member's production cost plus ten percent, whichever is greater.[14]

MAIN's rules require that, after the 59 minutes of reserve sharing, either WETO must have found and purchased energy from some seller on the grid to close the gap, or ComEd's system operator must shed load and eliminate ComEd's power supply shortage.[15] (The purpose of the rule is to prevent one utility with a problem from dragging down its neighbors with them.)

K. Load Shedding

In the event that ComEd's generation is insufficient to meet the load, MAIN's reserve sharing is insufficient (or past 59 minutes), purchases are insufficient, and interruptibles are insufficient, then ComEd has no remaining options other than to shed load. Depending upon the time scale, ComEd has three different load shedding scenarios

1. Anticipated Shed

If there is sufficient time, the system operator will notify the distribution operator (in ComEd's Distribution Dispatch and Control Center) that ComEd anticipates that a load shed might be necessary tomorrow, or the next day. The distribution operator will respond by sending personnel out into the field to man the distribution substations.

If a load shed indeed becomes necessary, the system operator will direct the distribution operator to shed load, how big a shed (how many MW) is needed, and for how long he expects the shed to be necessary.

The distribution operator has a "shed list" of groups of distribution feeders, and how many MW of load reduction each group is expected to produce. The shed list is prepared by ComEd's planning department.[16] They have pre-selected feeders that they believe will avoid critical loads: hospitals, police stations, fire houses, and life-support customers.[17]

When directed by the system operator, the planning department's pre-selected feeders are shed by the distribution operator, interrupting the service to all of the customers on those feeders.

Feeders on SCADA are shed by the distribution operator using SCADA. Feeders not on SCADA are manually shed by the personnel who have been sent out to the substations.

If the load shed extends for more than three hours, then the next group of feeders in the shed list are shed and service is restored to the first group shed This is referred to as rolling blackouts.

The distribution operator keeps a "bookmark" in the shed list to insure that ComEd's next load shed always begins where the last one left off: no group of shed list feeders is shed a second time until every other group of shed list feeders has been shed first.

In Illinois, as in most other jurisdictions, the shed list is the sole responsibility of ComEd. In a few other jurisdictions, the utility's regulatory body must pre-approve the shed list.

2. Push-Button Sheds

If there is insufficient time to prepare the distribution operator, the system operator will notify the distribution operator to shed load now, and how much. The distribution operator will respond by shedding those feeders, on the planning department's shed list, next after the bookmark, which are under SCADA control. A push-button shed will consume more groups of feeders from the shed list to compensate for the feeders that are not yet on SCADA and which thus could not be shed.

3. Under-frequency Shed

Some system disasters come on so quickly that there is no time for operators to respond. MAIN requires that all of its members equip their distribution substations with "under-frequency relays" that monitor the electric frequency of the grid and shed huge blocks of load automatically whenever the grid's frequency drops significantly below sixty Hertz.

L. Operator Training

System operators are similar to airline pilots in that (hopefully) their work is calm, routine, and repetitious. Nonetheless, both must always be prepared to perform perfectly under the stress of an emergency. Both should train for emergencies in simulators, computer-driven machines that reproduce the working environment so that they can safely practice their responses to the emergencies that are simulated by the computer. Unlike some other electric utilities, ComEd had no simulation training facility for its operators.[18] (ComEd reported that in early 2000 it began using a simulator.) ComEd provided its system operators with extensive written materials such as "Emergency Response Manual," procedure manuals, notification manuals, and the Storm Restoration Manual.[19] Since about 1998, new Distribution and System Operators have received formal classroom training, as well as on-the-job training before they were allowed to operate on the system. Also, all Distribution and System Operators received cyclical training on procedures and safe work practices.

M. Wholesale Market

In keeping with the electric industry's movement towards competitive free markets, ComEd has ended the system operator's former role in purchasing power from outside power suppliers. Previously, the system operator monitored the incremental cost rate of the power supply and compared it with those of peer system operators in neighboring utilities. If operator discovered that a neighbor's incremental cost rate was less than ComEd's, then the operator saved money by purchasing power from the neighbor rather than generating it. If the operator discovered that a neighbor's incremental cost rate was more than ComEd's, then the operator made money by selling power to the neighbor rather than having them generate it.

Those former power purchase and sales responsibilities have all been taken over by WETO, ComEd's Wholesale Energy Trading Office.[20] WETO prepares its own load forecast. WETO then conducts a trading floor activity (much like a commodity broker's) where they buy and sell contracts for power to match against their load forecast.

After WETO and other energy traders who are using ComEd's transmission system strike their contracts, those contracts are turned over to the system operator for execution. The operator dispatches contracts for the sale of power like he previously dispatched power plants using the contract's sales price instead of the models for incremental fuel cost to achieve economic dispatch.

As operational constraints develop on the transmission system, *e.g.* congestion, or a problem at a power supply generation plant, the system operator published a public notice. WETO, and all of the other users of ComEd's transmission system, can then respond. If ComEd calls upon MAIN's reserve sharing, the system operator notifies WETO (and all other users of ComEd's transmission system) and WETO must try to buy replacement energy before the 59-minute time limit expires.

All communications between the system operator and WETO are constrained and public. This is done to avoid the appearance of a conflict of interests, such as having ComEd's WETO making an excessive market profit because it was privy to better information about the condition of ComEd's transmission system.

N. Open Access

The Federal Energy Regulatory Commission *(FERC)* Order 888, and succeeding orders, mandate "open access" to transmission lines. ComEd, and the other members of the MAIN Reliability Council, have contracted with MAIN to provide some of FERC's mandated services, which are discussed below.[21] Each day, MAIN receives its members' load forecasts, anticipated generation schedules, and transmission usage reservations. Working for MAIN, a group of ComEd engineers then calculates how much unused transmission capacity can be expected to be left over and available. This is called Available Transmission Capacity *(ATC)*.[22]

MAIN then posts the ATC on its "Open Access Same-time Information System" *(OASIS)*. MAIN's OASIS is an Internet site that was started up in 1996,[23] where potential buyers of transmission service can view what transmission is available, and submit a request for a reservation to use the transmission. The reservations are granted on a first-come, first-served basis, among classes of service. Renewals of long term "firm" service had first priority. New short-term, non-firm service had the lowest priority. The rates for the service are published in the transmission provider's Open Access Transmission Tariff *(OATT)*, which has been approved by FERC.[24]

ComEd's system operators must monitor their portion of MAIN's OASIS and "tag" the sales of ComEd's transmission services by marking the transaction with a number, and entering it into ComEd's data base so that the Block House's computer will be aware of the transmission usage, accommodate it, and render a bill to the user.[25]

Under FERC's Order 888, ComEd's WETO is treated like any other user of ComEd's transmission system. They must submit requests for reservations through OASIS and pay ComEd's OATT rates.

O. MISO

In 1996, several utilities began discussion on forming the Midwest Independent System Operator *(MISO)*. In January, 1998, nine utilities filed a plan with FERC for MISO. In September, 1998, FERC approved their OATT and their operator plan. MISO is now scheduled to start operations in November 1, 2001. When formed, MISO will take over as the system operator for the combined transmission systems of all of its members, 100kV and above. However, members will continue to regulate their existing control areas. ComEd expects to the a member of MISO.[26]

III. Conclusions

1. ComEd had a state-of-the-art SCADA for its transmission system.

System operators in ComEd's Block House have a state-of-the-art SCADA system with which to conduct their transmission system surveillance, detect likely-false substation data, receive alarms for system problems, receive warnings for potential system problems, and execute their control and dispatch of the system.

2. ComEd's system operators and distribution operators were provided with appropriate pre-planned operational procedures. ComEd's system operators did not have a training simulator.

Unlike some electric utilities, ComEd had no simulation training facility for its system operators to safely train by practicing their responses to emergencies in the simulator. There was little evidence, however, that the lack of a training simulator affected transmission system reliability. Therefore, Liberty did not include a recommendation for ComEd to have a simulator.

System operators receive off-line assistance from transmission operations planning engineers and ComEd's Security Analysis Program. They have extensive written materials: "Emergency Response Manual," procedure manuals, notification manuals, and the Storm Restoration Manual. Distribution operators have the shed list to support the system operator with pre-planned load shedding.

3. ComEd had effective management oversight of its system operators.

4. ComEd's system operators conducted economic dispatch effectively.

The high correlation between each unit's position on ComEd's merit order list, and that unit's share of contribution to ComEd's 1999 total power supply, demonstrated that ComEd's economic dispatch was effective.

5. ComEd's success in selling off its excess nuclear generation during low-load conditions was unusual.

In many other parts of the United States, utilities with similar low-load problems have had to resort to negative price sales and pay other utilities to take their early morning excess nuclear generation.

IV. Recommendations

There are no recommendations with this chapter.

Endnotes for Chapter Twenty-Five

[1] Interview #9, Tom Wiedman, January 11, 2000.
[2] Response to Data Request 804.
[3] Response to data request 528, Commonwealth Edison's "Federal Energy Regulatory Commission Form Number One – Year Ended December 31, 1999" pages 402-403.4 lines 1, 12 and 19.
[4] Response to data request 528, Commonwealth Edison's "Federal Energy Regulatory Commission Form Number One – Year Ended December 31, 1999" page 327.
[5] Response to Data Request #643, Interview #135, Dennis Friend, April 20, 2000, and Interview #126, Bill Fredricksen, April 6, 2000.
[6] Response to data request 528, Commonwealth Edison's "Federal Energy Regulatory Commission Form Number One – Year Ended December 31, 1999" page 401b line 35.
[7] Interview #11, Bill Fredricksen, January 12, 2000.
[8] Interview #11, Bill Fredricksen, January 12, 2000, and Interview #126, Bill Fredricksen, April 6, 2000.
[9] Response to Data Request #642, Interview #135, Dennis Friend, April 20, 2000, and Interview #126, Bill Fredricksen, April 6, 2000.
[10] Response to Data Request #644, Interview #126, Bill Fredricksen, April 6, 2000.
[11] Response to data request 518, Monthly Statistics for August 1999, and January 2000.
[12] Interview #11, Bill Fredricksen, January 12, 2000, and ComEd comments on draft report September 19, 2000.
[13] Response to Data Request #645, Interview #126, Bill Fredricksen, April 6, 2000.
[14] Interview #11, Bill Fredricksen, January 12, 2000.
[15] Interview #15, Ron Szymczak, January 10, 2000, Interview #11, Bill Fredricksen, January 12, 2000.
[16] Interview #127, Robert Rush, April 4, 2000.
[17] In a different utility, the shed list purposely includes all hospitals, police stations, and fire houses to be shed first because these facilities have their own back-up generators and are unharmed by being shed.
[18] Interview #126, Bill Fredricksen, April 6, 2000, on-site observations, and ComEd comments on draft report September 19, 2000.
[19] Response to Data Request #637, Interview #10, Dan Sleezer, December 16, 1999, and Interview #127, Robert Rush, April 4, 2000.
[20] Interview #135, Dennis Friend, April 20, 2000.
[21] Interview #46, Steve Naumann, January 10, 2000.
[22] Interview #15, Ron Szymczak, January 10, 2000, Interview #49, Jennifer Sterling, February 1, 2000.
[23] Interview #9, Tom Wiedman, January 11, 2000.
[24] Interview #49, Jennifer Sterling, February 1, 20000.
[25] Interview #10, Dan Sleezer, December 16, 1999.
[26] Interview #46, Steve Nauman, January 10, 2000, Interview #50, Bob Schrage, February 3, 2000.